H. OPERATING DATA

H.1 INJECTION RATE AND VOLUME

The estimated average injection rate is: 165 gallons per minute (gpm) for each well.

The estimated average injection volume is: 7,128,000 gallons per month (30 days) per well for each well.

The requested maximum injection rate is: 215 gpm for each well.

The requested maximum injection volume is: 9,288,000 gallons per month (30 days) for each well.

The estimated average injection rate is based on measured injection rates in nearby wells injecting into the Mt. Simon Formation.

H.2 INJECTION PRESSURES

Based on the following calculations, the requested maximum surface pressure (MASIP) for variable specific gravities are as follows:

[(0.80 pound per square inch per foot [psi/ft] – (0.433 psi/ft x specific gravity)) x depth] – 14.7 pounds per square inch gauge (psig)

[(0.80 psi/ft – (0.433 psi/ft x 1.00)) x 3,470] – 14.7 psi = 1,259 psig

Where: Specific Gravity = 1.00

Depth to top of the Mt. Simon Formation = 3,470 feet

Fracture Gradient = 0.80 psi/ft

[(0.80 psi/ft – (0.433 psi/ft x 1.21)) x 3,470] – 14.7 psi = 943 psig

Where: Specific Gravity = 1.21

Depth to top of the Mt. Simon Formation = 3,470 feet

Fracture Gradient = 0.80 psi/ft

A table of MASIP as a function of Specific Gravity is provided in Table H-1.

Table H-1 MASIP as a Function of Injectate Specific Gravity

INJECTATE SPECIFIC GRAFIVTY	MASIP (PSIG)
1.00	1259
1.05	1184
1.10	1109
1.15	1033
1.20	958
1.21	943

H.3 WASTE

H.3.1 SOURCE

The proposed injectate will consist of brine from the solution mining of the Salina Formation to create storage caverns. The specific gravity of the brine is expected to range from 1.00 to 1.21. The injectate pH will be approximately 7.24 at 70 F°.

H.3.2 WASTE ANALYSIS

A typical Wastewater analysis is provided in Table H-2 and as Table 1-1 in Appendix D, the Waste Analysis Plan discussed in Attachment P.

H.3.3 CORROSION MONITORING

The corrosivity of the wastewater injectate will be monitored with corrosion coupons placed in the injectate stream. Well component materials will be selected using standard engineering specifications for specific functions with a balance between engineering serviceability and economics.

Table H-2 Estimated Wastestream Analysis for Proposed Monitored Parameters

PARAMETER	UNITS	READING
pH		7.24
Resistivity	ohm-meter	0.046
Temperature	°F	70
ANIONS		
Chlorides	mg/L	193,000
Sulfates	mg/L	2,989
Sulfides	mg/L	ND < 1
Carbonates	mg/L	ND < 10
Bicarbonates	mg/L	150
CATIONS		
Sodium	mg/L	112,500
Calcium	mg/L	1,940
Magnesium	mg/L	199
Barium	mg/L	ND < 1
Iron (total)	mg/L	ND < 1

I. FORMATION TESTING PROGRAM

I.1 PROCEDURES TO VERIFY DEPTH OF THE LOWERMOST USDW, IF NEEDED

The base of the USDW within the AOR is estimated to be at 350 feet bgs at the base of the Sylvania Sand.

At each proposed well, the surface hole will be drilled to 470 feet (120 feet below the base of the USDW) to allow for geophysical logging to be conducted across the base of the USDW. The logging to be conducted is discussed further in Attachment L. The resistivity of the formation water will be calculated using the resistivity and porosity values recorded on the logs.

No open-hole testing is planned to sample the lowermost USDW during the installation of the wells.

I.2 PROCEDURES TO OBTAIN EXTRAPOLATED FORMATION PRESSURE

The following procedures are to obtain extrapolated formation pressure in porous and permeable zones within approximately 500 feet of the top of the injection zone.

As discussed in Attachments L and M, a series of drill stem tests may be conducted during drilling. The intervals to be tested will be determined from data collected while drilling. The open-hole drill stem tests will provide preliminary reservoir information regarding permeability-thickness product and bottom hole pressure.

The open-hole testing, combined with the open-hole geophysical log interpretations, will determine the primary injection zone to be targeted during well completion. Casing will be set at the top of the selected injection zone and cemented as described in Attachments L and M. Injection and pressure falloff testing will be conducted as detailed in Steps 10 through 12 of the Completion Procedure discussed in Attachment L.

The original formation pressure obtained from the pressure falloff testing will be used to calculate the formation pressures in porous zones within 50 feet of the top of the injection zone. The specific gravity of the fluid will be measured from samples of the formation fluid recovered in Steps 5 and 6 of the Completion Procedure discussed in Attachment L.

The following equation will be used to extrapolate pressure to a well depth within 500 feet from the top of the injection zone:

$P_D=P_L-0.433\ \gamma^f(L-D)]$

Where:

P_D = Extrapolated formation pressure at depth D feet bgs, psia

P_L = Formation pressure measured at depth L feet bgs, psia

γ^f = Specific gravity of formation fluid sample recovered from the injection interval

L = Depth bgs of pressure measurement taken in the injection interval

D = Depth bgs of calculated pressure in injection interval

I.3 SAMPLING AND ANALYSIS PROCEDURES FOR FORMATION FLUID

When the primary injection interval is determined, the first aquifer overlying the confining zone will be sampled utilizing a wireline conveyed repeat formation tester while conducting the open-hole geophysical logging. A standard water analysis of the formation fluid (Section L.2) will be conducted to determine physical and chemical properties.

I.4 COLLECTION AND ANALYSIS OF CORES

As previously discussed, the primary injection zone will be determined during drilling of the wells. Consequently, the confining and injection zone will be sampled by sidewall coring after the geophysical logging. Full-hole cores will be obtained in specific intervals during the drilling of future wells as needed.

Physical core analysis will include lithologic descriptions. Rock density, porosity, and air permeability will be determined on selected core samples. In addition, permeability to both waste and brine will be determined on selected plug samples taken from obtained core. Both horizontal and vertical permeability will be measured. Brine and waste permeability measurements will be run utilizing methods with a high range of accuracy (10^{3} to 10^{-6} millidarcy [md]).

Testing for mechanical rock properties will include determinations of Young's Modulus, Poisson's Ratio, tensile strength, and bulk compressibility. Selected samples from each core will be tested. Injectate compatibility testing will be conducted with fluids and matrix material derived from the injection zone.

I.5 FRACTURE CLOSURE PRESSURE DETERMINATION

Fracture closure pressure will be determined during the step-rate test of the injection zone discussed in Attachment L. This data will be collected in support of the geophysical calculations of the mechanical properties of the formation.

I.6 PROCEDURES FOR INJECTIVITY/FALL-OFF TESTING

Injection/fall-off test procedures are included Attachment L. The testing will be performed in accordance with EPA Region 5 Guidelines for Reservoir Testing (Regional Guidance #6). The rate and volume of fluid to be injected will be determined from preliminary injection testing results.

J. STIMULATION PROCEDURE

The need for any type of stimulation program will be determined after the well has been drilled and tested; however, it is not anticipated to be needed. Should the results of the injectivity testing program performed after the well has been constructed indicate stimulation is necessary to achieve the desired injection rate, the well will be chemically enhanced to reduce formation skin damage. The injection interval may be treated with a hydrochloric acid pre-treat, a mud acid main treat, and a hydrochloric acid post-treat.

This operation will consist of placing the acid across the entire injection interval in sequence allowing the acid to soak and then flow back out of the well after post flush. The exact volume, make-up and placement technique of the acid will be developed after the necessary performance data from the proposed injection wells have been collected and analyzed.

Below is an estimated stimulation program to be verified. All chemicals involved in this stimulation activity will need to be stored and handled in accord with site and industry safe working practice and regulatory working practice. A plan will be developed and approved by all parties involved prior to bringing chemicals on site, after requirement has been defined. The EPA will be notified prior to any acid stimulation of the injection formation. It should be noted that during acid stimulation, the annulus pressure may not be maintained at a 100 psi differential over the injection pressure.

Pre-Flush:

5,000 gallon 10% Hydrochloric Acid

250 gallon Well Stimulator

10 gallon Inhibitor

10 gallon Iron Reducing Agent

10 gallon Non-Emulsifying Agent

10 gallon Perm Clay Stabilizer

Main Flush:

18,000 gallon 12% Hydrochloric/3% Hydrofluoric (Mud Acid)

36 gallon Inhibitor

180 gallon Well Stimulator

36 gallon Iron Reducing Agent

36 gallon Non-Emulsifying Agent

36 gallon Perm Clay Stabilizer

Post Flush:

2,000 gallon 10% Hydrochloric Acid

20 gallon Well Stimulator

4 gallon Inhibitor

4 gallon Iron Reducing Agent

4 gallon Non-Emulsifying Agent

4 gallon Perm Clay Stabilizer

K. INJECTION PROCEDURE

K.1 WASTE STREAM FLOW

A simplified schematic showing the plant outline indicating the proposed waste stream flow is provided as Figure K-1.

K.2 DESCRIPTION OF FACILITIES

The cavern solution mining system will be composed of two smaller connected systems: 1) the water injection system; and 2) the brine disposal system. The brine disposal system incorporates solids separation, a booster pump to pressurize the brine, a fine particle filtration system, brine disposal pumps, a disposal well, and a well annulus monitoring system. This leaching system will not be a part of the facility until future cavern development starts.

Brine will be injected into the wells with multiple, variable speed positive displacement injection pumps connected in parallel. A sample tap will be located on the injectate flow line before the injection pumps.

Figure K-2 provides a simplified schematic diagram showing the flow of the injectate through storage, filtration and pumps to the injection well.

K.3 DESCRIPTION OF INJECTION PUMPS

The facility is proposing to utilize two centrifugal injection pumps with a rating of 350 horsepower and operating pressure of 2000 psi.

K.4 DESCRIPTION OF ANNULUS PRESSURE MAINTENANCE SYSTEM

The annulus pressure maintenance system at each wellhead will consist of a 200-250 gallon, nitrogen pressurized pot that is filled with inhibited fluid and connected to the annulus of 4-½-inch injection tubing and 9-⅝-inch protection casing. The annulus pot will have a sight glass to allow the fluid level to be monitored visually as well as an electronic transmission that will be monitored continuously at the main computer terminal.

The annulus pressure will be maintained at least 100 psi above the maximum wellhead injection pressure. An analog pressure gauge will be connected to the well annulus and a pressure transducer will also be connected to the well annulus that transmits a signal to a digital converter. The digital output of the annulus pressure will be transmitted to a computer for continuous monitoring of the annulus pressure.

A female coupling will be connected below the analog annulus pressure gauge to allow for independent determination of annulus pressure. A schematic diagram of the anticipated well head and annulus maintenance system has been included as Figure K-3.

K.5 DESCRIPTION OF ALARM AND SHUT-OFF SYSTEM

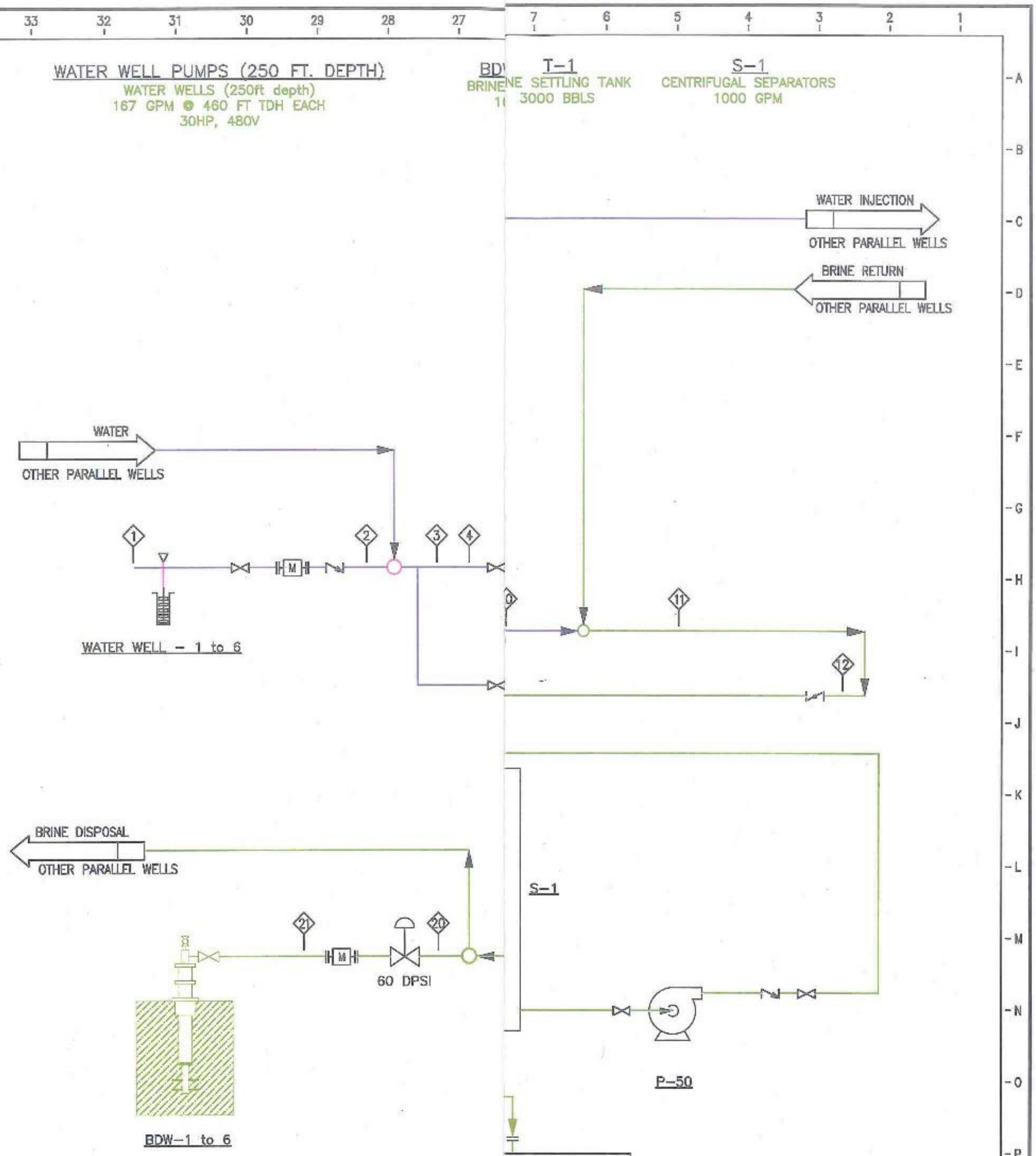
Continuous measurements of injection pressure and annulus pressure will be monitored by a shut-down system. The injectate specific gravity will be measured daily during cavern leaching operation. The injectate specific gravity will be measured weekly during cavern hydrocarbon storage operation when the wells will transition to intermittent use and the injectate brine will be fully saturated or nearly fully saturated. The system will shut down the injection pumps if the wellhead injection pressure exceeds a predetermined MASIP determined by calculations based on the most recent measured specific gravity or if the annulus pressure drops below a predetermined minimum allowable annulus pressure. All instrumentation will be enclosed in weatherproof housing located near the deep well.

In accordance with regulations, the annulus pressure will be kept at a minimum of 100 psi over the injection pressure and the annulus pressure will have a maximum of 150 psi above the maximum calculated MASIP. The alarm and shutdown will occur when the annulus pressure drops below 100 psi above this MASIP. The specific gravity variable injection pressure and annulus pressures will be monitored continuously with analog and digital gauges on the wells. Pressure transducers and flow measurement will be tied in with the well's main computer terminal to compute the MASIP as well as flow rate.

All personnel will be trained in the operation of the well, including fluid quality, alarms, shutdowns, and notification procedures. Operators will be in continual attendance during well operation. In the event that an alarm sounds, facility personnel will notify a trained operator who will investigate and correct the problem. If upon investigation, it is determined that a well lacks mechanical integrity, or if continued monitoring otherwise indicates that the well may be lacking mechanical integrity, then Buckeye Terminals, LLC will:

1. cease injection of waste fluids (unless authorized by the executive director (MDEQ) to continue or resume injection;
2. take the steps necessary to determine the presence or absence of a leak; and
3. notify the MDEQ within 24 hours after the alarm or shutdown occurs.

List of Figures in Attachment K



VARIABLE NODE:	1	2	3	4	5	
Fluid	Water	Water	Water	Water	Water	Wa
Specific Gravity (Water = 1.0)	1.0	1.0	1.0	1.0	1.0	1
Viscosity (centipoise)	1.0	1.0	1.0	1.0	1.0	1
Pressure (psig)*	-108	77	77	50	331	3
Flow Rate (US Gallons/minute)	167	157	1000	1000	1000	10
Nominal Pipe Size (inches)	-	4 (HDPE)	10 (HDPE)	10 (HDPE)	8	
Pipe ID (inches)	-	3.794	9.062	9.052	7.981	7.9
Fluid Velocity (feet/second)	-	4.7	5.0	5.0	6.4	6

S LP.

GENERAL NOTES

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16285 PARK TEN PLACE, SUITE 400
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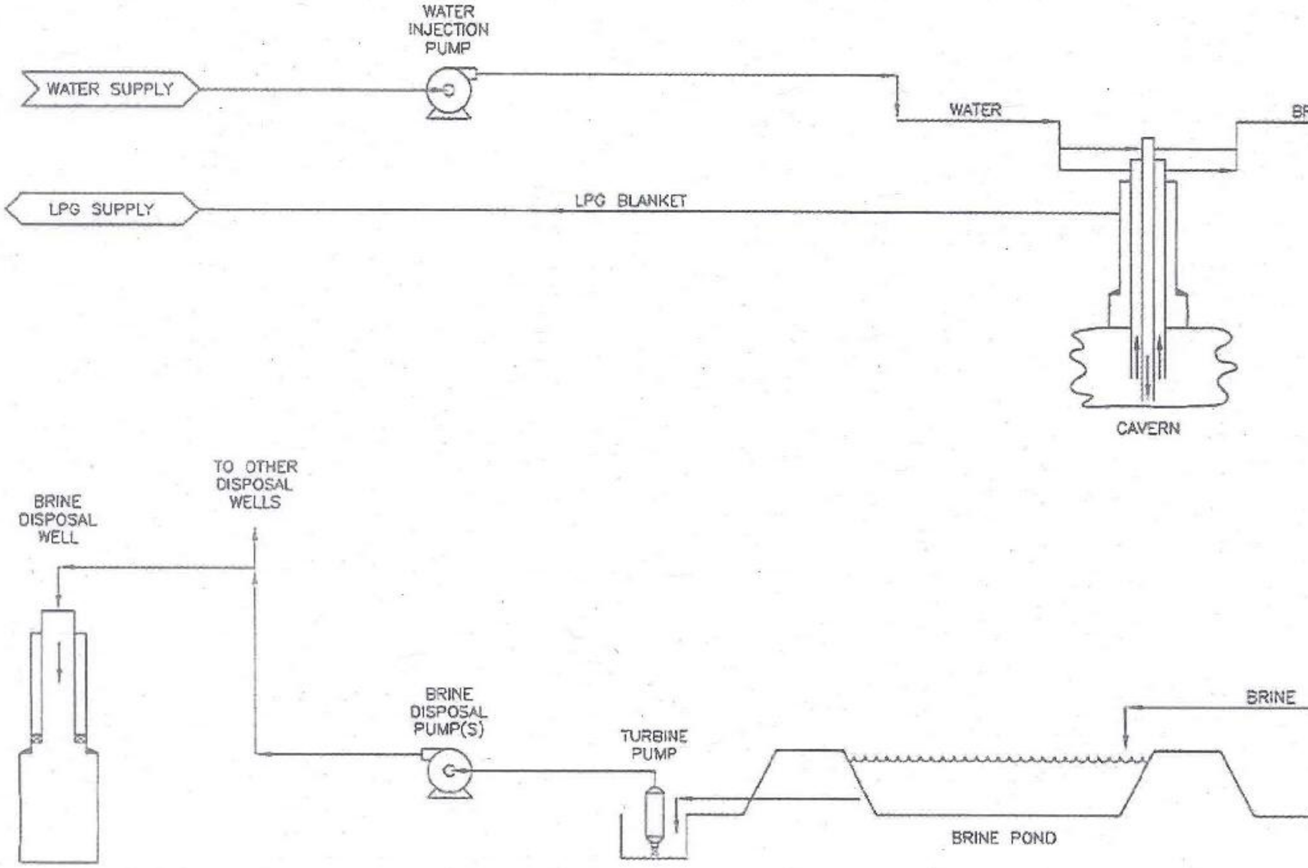
SIMPLIFIED SCHEMATIC OF PROPOSED WASTE STREAM FLOW
LEACH PLANT
WOODHAVEN
BUCKEYE TERMINALS, LLC

DESIGN BY: HK DATE: 4/21/14	DRAWN BY: RMM DATE: 4/21/14	SCALE: NONE
CHECKED BY: HK DATE: 4/21/14	APPROVED BY: HK DATE: 4/21/14	PROJECT No: 192065A
FILE NAME: FIGURE K-1	DRAWING No.	LATEST REVISION: B



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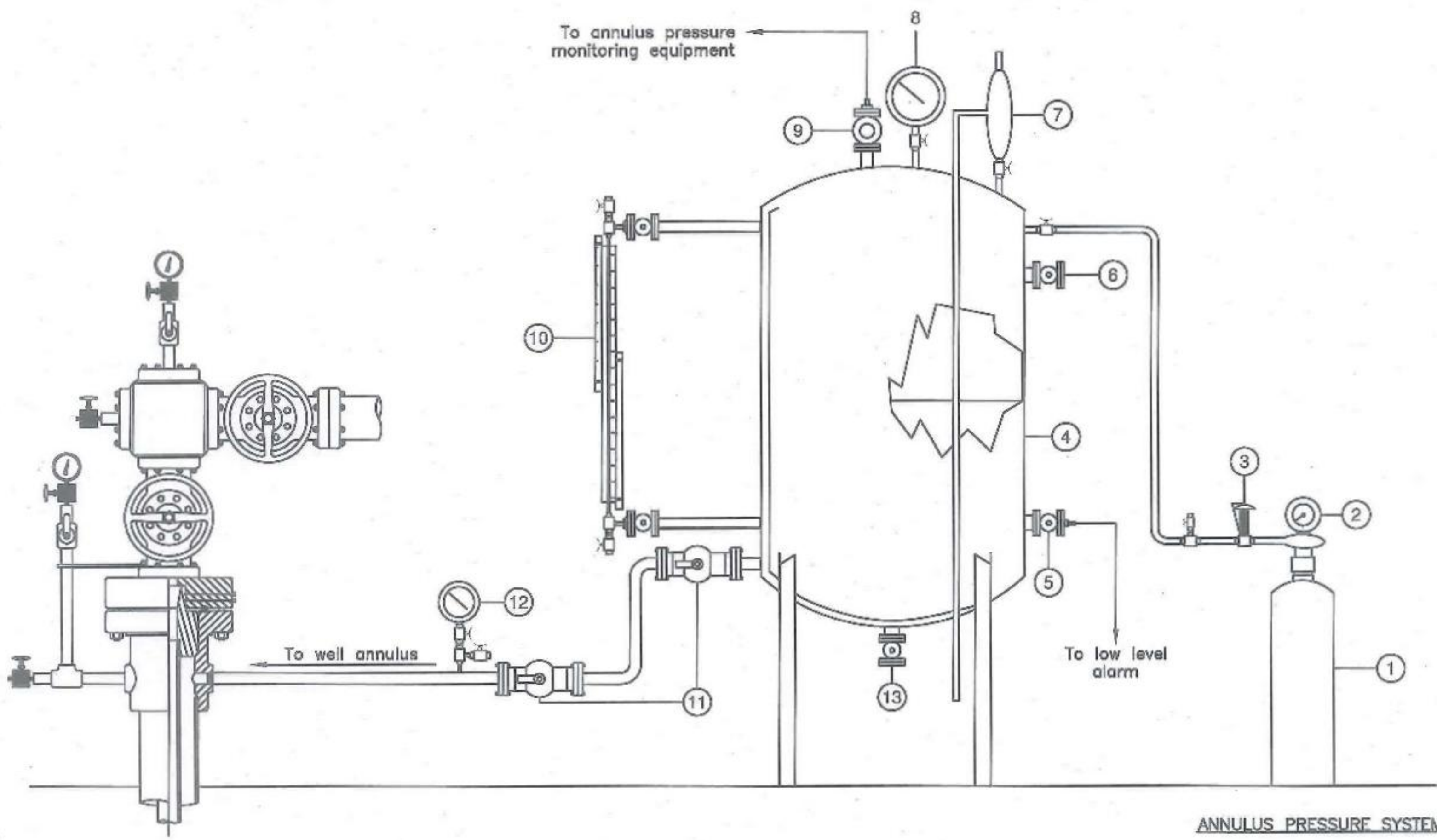
BUCKEYE TERMINALS, LLC
WOODHAVEN TERMINAL
WAYNE COUNTY, MICHIGAN

SIMPLIFIED SCHEMATIC DIAGRAM OF INJECTATE FLOW

Job No.	192065A										
Design:	WDD	Drawn:	WDD	Checked:	GM	Date:	08/21/17	Scale:	NTS	Drawing No.	K–2



ANNULUS PRESSURE SYSTEM DETAILS

1. Nitrogen supply tank
2. Nitrogen supply tank pressure gauge
3. Nitrogen pressure control valve
4. Annulus pressure pot
5. Annulus fluid level low alarm
6. Annulus pressure pot fill valve
7. Annulus pressure pot safety valve
8. Annulus pressure pot pressure gauge
9. Annulus pressure pot pressure measuring point
10. Annulus pressure pot sight glass
11. Annulus block valves
12. Pressure gauge
13. Annulus pressure pot drain valve

NOT TO SCALE

wsp

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BUCKEYE TERMINALS, LLC
WOODHAVEN TERMINAL
WAYNE COUNTY, MICHIGAN

PROPOSED WELLHEAD AND ANNULUS PRESSURE SYSTEM SCHEMATIC

Job No.	192065A								
Design:	WDD	Drawn:	WDD	Checked:	GM	Date:	08/21/17	Scale:	NTS
Drawing No.	K-3								

L. CONSTRUCTION PROCEDURES

L.1 CONSTRUCTION PROCEDURES

The injection zone will include the Eau Claire Formation and the Mt. Simon Sandstone (approximately 3,470 to 3,730 feet bgs). The Utica shale, the Trenton Limestone, and the Trenton/Black River Dolomite constitute the confining zone (2,060 to 3,470 feet bgs).

The construction procedures below are developed to drill and test the individual zones to evaluate and maximize the potential for injection. Intermediate casing will be set below the lowermost formation that is productive of hydrocarbons in the immediate area. The injection long-string casing will be set above the selected injection interval and cemented to surface.

The estimated timetable for drilling, logging, and formation testing is provided on Table L-1.

L.1.1 DRILLING AND COMPLETION OF VERTICAL WELLS (BDW-1 AND BDW-4)

1 Clear and level the location to accommodate rotary drilling equipment. The pad will be constructed in a manner that the entire pad is covered with a liner surrounded on all sides with spill berm. It is anticipated that salt-based drilling fluid will be required; therefore, the cuttings will be processed through a closed loop mud system that will dewater cuttings and recycle fluids. Solids and fluids will be disposed of in an environmentally safe and proper way.

2 Set conductor casing by driving or augering 20-inch, 0.625-inch minimum wall thickness, conductor casing to 50 feet bgs or refusal.

3 Move in and rig up a rotary drilling rig and equipment capable of a total depth of 8,000 feet. Rotary rig has to have all inspections and certifications up to date and have documentation to prove it. Install a riser pipe on the conductor casing to contain drilling fluid while drilling the surface hole. A proposed drilling fluid program can be found in Appendix C.

146.12(d)(1)

4 Mix a fresh water gel drilling fluid to drill the surface hole. Drill a 17-½ inch hole to 470 feet bgs. Run deviation surveys at the base of the conductor casing and at 50-foot intervals to 470 feet. The maximum allowable deviation of the surface hole will be 0.75 degree from vertical at 470 feet.

5 Run geophysical logs on the surface hole to verify the base of the USDW (Table L-2).

6 Run 13-3/8 inch surface casing as specified in Table M-2 to the total depth of the surface hole. Cement the surface casing to ground surface as detailed in Table M-1. Should the cement fail to circulate to surface or fall back bgs, run 1-inch pipe to the top of the cement and fill the annulus to the surface with standard cement.

146.12(d)(2)(i)(B)

7 Run a temperature survey between 8 and 12 hours after the cement is in place to locate the top of the cement if it does ~~not~~ circulate to surface. Allow 24 hours for the cement to set before releasing the casing from the slips or elevators.

8 Cut the surface casing off at ground level and install a 13-5/8 inch, 3000-psi working pressure, weld-on casing head. Pressure test the surface casing to 1000 psig according to EPA Region 5 guidelines.

9 Run a 12-¼ inch bit and drill the cement out of the shoe joint to the base of the surface casing.

10 Rig up a 24-hour, manned, mud logging unit to collect and evaluate samples, plot drilling time, and detect hydrocarbon shows while drilling.

146.12(d)(1)

11 Drill a 12-1/4 inch hole to the depth of 650' with the fresh water drilling system. Conduct deviation surveys on 90-foot intervals with a maximum deviation change of 1 degree per 100 feet and a total deviation not to exceed 5 degrees from vertical at any point in the well. At 650' displace and convert the drilling fluid system to a salt-saturated system to protect the salt beds from washing out in the Salina interval. Maintain good quality salt saturated drilling fluid and a closed loop solids separation system to contain and isolate drill cuttings for disposal.

146.12(d)(2)(ii)(A)

12 Drill 12-1/4" hole 150' below the to the base of the B Salt to approximately 1310' BGL. Circulate and condition hole and run geophysical logs from 1310 feet to the base of the surface casing.

13 Run 9-5/8", 36 lb/ft, J-55, intermediate casing to total depth. Run centralizers on every other casing collar from total depth to surface. Cement with salt saturated class G cement.

14 Center the casing in the wellhead and install the casing slips without moving the casing. Wait on cement a minimum of 24 hours. Cut the casing and install the "B" section of the wellhead. Nipple up blowout preventors.

ii(c)

15 Drill out the cement stage collar with an 8-3/4" drill bit assembly and clean out to the float collar. Run a cement bond log from total depth to the surface. Pressure test the casing to 1500 psi for 20 minutes per MDEQ and EPA requirements.

ii

16 Drill out cement and shoe with stabilized 8-3/4" drill bit assembly and continue to drill to total depth at the base of the Mt Simon (approximately 3730 feet) as determined by sample analysis and on-site evaluation.

ii

17 Run geophysical logs as detailed in Table L-2. Determine the optimum setting depth for the 5-1/2", 15.5#, LTC casing.

18 Fill the bottom of the well with sand to the depth of the casing shoe as determined from logs and other testing. Run 5-1/2" casing, according to the detail in Table M-2, to the desired depth. Cement the casing annulus to the surface, in one or two stages, as detailed in Table M-1.

ii(c)

19 Run a temperature survey between 8 and 12 hours after the cement is in place to locate the top of the cement if it does not circulate to surface. Run 1-inch pipe and fill the annulus to surface if necessary.

ii(c)

20 After 48 hours waiting time, run a cement bond log from the stage tool (if run) or the float collar to surface. Set the casing slips release the 5-1/2" casing. Make a final cut on the 5-1/2" casing and install an 7-1/16-inch, 3000-psi tubing head.

21 Install blowout preventers and drilling nipple. Run a 4-5/8" drilling assembly on 3-1/2" drill pipe. Pressure test the casing above the stage collar (if present) to 1500 psi according to EPA guidelines. Drill out the stage collar and pressure test the casing and the stage collar. Clean out the casing to the shoe joint.

ii(c)

22 Run a cement bond log along the full length of the 5-1/2" casing if not done previously. Conduct the final intermediate casing pressure test according to EPA guidelines to certify mechanical integrity.

23 Drill out the cement from the shoe joint and clean out the open hole below the casing to TD.

24 Displace the wellbore to 1% KCl water and secure the well with a cap.

25 Rig down and move out the drilling rig and equipment and restore location.

26 The well will be completed as described in the Completion section below.

L.1.2 DRILLING AND COMPLETION OF DIRECTIONAL WELL (BDW-2, BDW-3, AND BDW-5)

1 Clear and level the location to accommodate rotary drilling equipment. The pad will be constructed in a manner that the entire pad is covered with a liner surrounded on all sides with spill berm. It is anticipated that salt-based drilling fluid will be required; therefore, the cuttings will be processed through a closed loop mud system that will dewater cuttings and recycle fluids. Solids and fluids will be disposed of in an environmentally safe and proper way.

2 Set conductor casing by driving 20-inch, 0.625-inch minimum wall thickness, conductor casing to 50 feet bgs or refusal.

3 Move in and rig up a rotary drilling rig and equipment capable of a total depth of 8,000 feet. Rotary rig has to have all inspections and certifications up to date and have documentation to prove it. Install a riser pipe on the conductor casing to contain drilling fluid while drilling the surface hole. A proposed drilling fluid program can be found in Appendix C.

4 Mix a salt gel drilling fluid to drill the surface hole. Drill a 17-½ inch hole to 470 feet bgs. Run deviation surveys at the base of the conductor casing and on 50-foot intervals to 470 feet. The maximum allowable deviation of the surface hole will be 0.75 degree from vertical at 470 feet.

5 Run geophysical logs on the surface hole to verify the base of the USDW (Table L-2).

6 Run 13-3/8 inch surface casing as specified in Table M-2 to the total depth of the surface hole. Cement the surface casing to ground surface as detailed in Table M-1. Should the cement fail to circulate to surface or fall back bgs, run 1-inch pipe to the top of the cement and fill the annulus to the surface with standard cement.

7 Run a temperature survey between 8 and 12 hours after the cement is in place to locate the top of the cement if it does not circulate to surface. Allow 24 hours for the cement to set before releasing the casing from the slips or elevators.

8 Cut the surface casing off at ground level and install a 13-5/8 inch, 3000-psi working pressure, weld-on casing head. Pressure test the surface casing to 1000 psig according to EPA Region 5 guidelines.

9 Run a 12-¼ inch bit and drill the cement out of the shoe joint to the base of the surface casing.

10 Rig up a 24-hour, manned, mud logging unit to collect and evaluate samples, plot drilling time, and detect hydrocarbon shows while drilling.

11 Run a 12-¼ inch bit and stabilized drilling assembly. Drill a 12-1/4 inch hole to the depth of 650' with the fresh water drilling system. Conduct deviation surveys on 90-foot intervals with a maximum deviation change of 1

degree per 100 feet and a total deviation not to exceed 5 degrees from vertical at any point in the well. At 650' displace and convert the drilling fluid system to a salt-saturated system to protect the salt beds from washing out in the Salina interval. Maintain good quality salt saturated drilling fluid and a closed loop solids separation system to contain and isolate drill cuttings for disposal.

12 Drill 12-1/4" hole 150' below the to the base of the B Salt to approximately 1310' BGL. Circulate and condition hole and run geophysical logs from 1310 feet to the base of the surface casing.

13 Run 9-5/8", 36 lb/ft, J-55, intermediate casing to total depth. Run centralizers on every other casing collar from total depth to surface. Cement with salt saturated class G cement.

14 Center the casing in the wellhead and install the casing slips without moving the casing. Wait on cement a minimum of 24 hours. Cut the casing and install the "B" section of the wellhead. Nipple up blowout preventors.

15 Drill out the cement stage collar with an 8-3/4" drill bit assembly and clean out to the float collar. Run a cement bond log from total depth to the surface. Pressure test the casing to 1500 psi for 20 minutes per MDEQ and EPA requirements.

16 Trip out of the well and install drilling motor and mud tools to the bottom hole assembly (BHA). Maintain good quality drilling fluid and solids separation equipment to minimize the weight of the drilling fluid and minimize hole erosion and washout.

OR 30°? SEE DIAGRAM

? 17 Start building curve section and build to final inclination (maximum 35 degree) while maintaining 3 degrees per 100 feet build rate. Once final inclination reached, hold angle from to depth of 3,730 feet total vertical depth (TVD).

18 Run geophysical logs as detailed in Table L-2. Determine the optimum setting depth for the 5-1/2", 15.5#, LTC casing.

19 Fill the bottom of the well with sand to the depth of the casing shoe as determined from logs and other testing. Run 5-1/2" casing, according to the detail in Table M-2, to the desired depth. Cement the casing annulus to the surface, in one or two stages, as detailed in Table M-1.

20 Run a temperature survey between 8 and 12 hours after the cement is in place to locate the top of the cement if it does not circulate to surface. Run 1-inch pipe and fill the annulus to surface if necessary.

21 After 48 hours waiting time, run a cement bond log from the stage tool (if run) or the float collar to surface. Set the casing slips release the 5-1/2" casing. Make a final cut on the 5-1/2" casing and install an 7-1/16-inch, 3000-psi tubing head.

22 Install blowout preventers and drilling nipple. Run a 4-5/8" drilling assembly on 3-1/2" drill pipe. Pressure test the casing above the stage collar (if present) to 1500 psi according to EPA guidelines. Drill out the stage collar and pressure test the casing and the stage collar. Clean out the casing to the shoe joint.

23 Run a cement bond log along the full length of the 5-1/2" casing if not done previously. Conduct the final intermediate casing pressure test according to EPA guidelines to certify mechanical integrity.

24 Drill out the cement from the shoe joint and clean out the open hole below the casing to TD.

25 Displace the wellbore to 1% KCl water and secure the well with a cap.

26 Rig down and move out the drilling rig and equipment and restore location.

27 The well will be completed as described in the Completion section below.

L.2 COMPLETION

1 Prepare the location for a well completion rig. Move in a completion rig and ancillary equipment and sufficient 2-7/8 inch work string to reach total depth.

146.12(e)(2)

2 Rig up wireline and run a baseline temperature survey. Rig down wireline.

3 Run a 5-1/2-inch test packer on the work string and set the packer approximately 100 feet above the base of the casing.

146.12(e)(5)

4 Swab or jet well to recover formation fluid utilizing coiled tubing if necessary. Continue sampling until a representative recovery rate is established and a representative sample of fluid can be obtained for analysis.

146.12(e)(1)

5 Run a bottom hole pressure recorder to obtain a stabilized (12 hr minimum) bottom hole pressure. Pull the recorder and pull the workstring and packer out of the well.

146.12(e)(4)

6 Conduct a baseline injection test down the casing with filtered 1% KCL water. Determine the injectivity and establish whether stimulation of the formation with acid or fracture stimulation is necessary. Run a baseline casing inspection log.

7 Run a hydraulically set, retrievable packer with a 40 foot fiberglass tailpipe assembly and set it above the base of the casing. Run 3-1/2 inch injection tubing, and fill the annulus with corrosion inhibited brine water with oxygen scavenger. Latch into the packer (Refer to Figure M-6) and land the tubing in the wellhead.

8 Notify the EPA of the pending mechanical integrity test. Allow the well to stabilize thermally and conduct a Standard Annulus Pressure Test to confirm internal mechanical integrity of the casing, tubing, packer, and wellhead.

146.12(e)(3)

9 Place sufficient water into frac tanks to conduct a 12-hour injection test at the rate previously established. Run a surface readout bottom hole pressure transducer and set it near the base of the casing. Conduct a step rate injection test, plotting the rate and pressure to determine the fracture pressure as required, then shut down for one hour.

10 Inject fluid for 12 hours at a constant matrix injection rate while continuing to record bottom-hole pressure. Shut the well in and conduct a pressure falloff test for a time necessary to reach radial flow as determined by the derivative plot. Design pressure falloff test to measure interefence with nearby well(s), if applicable. At the completion of the pressure falloff, remove the pressure recorders from the well(s).

11 Begin injection into the well and run a radioactive tracer survey according to the guidelines of Region 5 for external mechanical integrity. Develop a fluid distribution profile from the moving surveys.

12 Rig down completion equipment and install the wellhead to secure the well while obtaining final permits for injection.

L.3 PROPOSED OPEN-HOLE AND CASED-HOLE LOGS

146.12

The proposed logging program is detailed in Table L-2. Multiple logging runs in the open hole may be required to evaluate the potential intervals available for injection. Mechanical integrity testing logs (cement bond logs, radioactive tracer log, and temperature, or noise or oxygen activation logs) are required prior to injection of brine.

The well(s) will be tested to demonstrate mechanical integrity as required by the guidelines of Region 5. Cement bond logs will be run on each casing string after the cement has cured. Each casing string will be pressure tested prior to drilling any new hole below the shoe joint.

A baseline casing inspection log will be run on the final casing string from total casing depth to surface. A baseline temperature survey will be conducted on the final casing and open-hole interval prior to the injection of significant volumes of water to provide a basis of comparison to future temperature surveys that may be run for demonstration of mechanical integrity.

After the injection tubing and packer have been installed, a radioactive tracer survey will be conducted to demonstrate external mechanical integrity of the cemented casing and the containment of injected fluid.

All tests will be conducted according to the most current edition of EPA Region 5 guidelines for mechanical integrity testing.

L.4 PROPOSED BUFFER FLUID AND VOLUME

After recovering samples of the formation water in the intended injection interval, compatibility tests will be run with samples of the intended waste stream. The samples will be tested at simulated bottom hole conditions to determine if precipitates form under those conditions. If the results are favorable, then no buffer fluid will be needed. If the results are in doubt, a volume of buffer fluid will be determined, based on the compatibility results to minimize direct contact of the connate water and the injectate.

146.12(e)(4)i(5)

List of Tables in Attachment L

TABLE L-1

ESTIMATED TIMETABLE FOR FIELD OPERATIONS (DRILLING, LOGGING, AND TESTING)
BUCKEYE TERMINAL, LLC
WOODHAVEN TERMINAL
WAYNE COUNTY, MICHIGAN

(Timeline is for Each Well)

	Week	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Days	7	14	21	28	35	42	49	56	63	70	77	84	91	98	105	112
	Task																
1	Build Location, Drive Conductor and Rig Up																
2	Drill, Log, Case and Cement Surface Casing to 450' (13-3/8' Casing 17-1/2" Hole) 470'																
3	Intermediate String Casing to 1,310'TVD / (9-5/8" Casing 12-1/4" Hole)																
4	Drill, Log Case and Cement Long String Casing to 3,490'TVD / (5-1/2" Casing 8-3/4" Hole)																
5	Drill and Log 8-3/4" Open Hole to 3730' TVD																
6	Set 9-5/8" X 4-1/2" Packer at 3470' TVD, 4-1/2" Injection String and Install Wellhead																
7	Run Injection Testing and MIT																

NOTES:
TVD - Total Vertical Depth
MD - Measured Depth
MIT - Mechnical Integrety Test

146.12(d) i(e)

Table L-2 Proposed Down-Hole Logging and Mechanical Integrity Testing Program

BOREHOLE/CASING DESCRIPTIONS AND INTERVALS	PROPOSED OPEN HOLE LOGS	PROPOSED CASED HOLE LOGS
Conductor Casing (20-inch to 50 feet bgs)	None	None
Surface Hole (17 ½ - inch to 450 feet) 470'? Surface Casing (13 3/8-inch)	Spontaneous Potential Gamma Ray Resistivity Comp. Neutron Density Comp. Formation Density 4-Arm Caliper	Cement Bond Variable Density Gamma Ray Temperature
Open Hole 12 ¼ - inch 470'? 450 feet to 1,310 feet bgs	Spontaneous Potential Gamma Ray Resistivity 4-Arm Caliper	Cement Bond Variable Density Gamma Ray Temperature
Open Hole 8 ¾ - inch 1,310 feet bgs to Total Vertical Depth (TVD)	Spontaneous Potential Gamma Ray Resistivity Comp. Neutron Density Comp. Formation Density Long Space Sonic Log 4-Arm Caliper	Cement Bond Variable Density Gamma Ray Temperature
Completion Logs Surface to Total Depth Including both cased and open hole intervals		Baseline Differential Temperature Survey Bottomhole Pressure Falloff Test Radioactive Tracer Survey Post-Injection Differential Temperature Survey

M. CONSTRUCTION DETAILS

M.1 PROPOSED WELL CONSTRUCTION

A schematic of each of the proposed wells is included as Figures M-1 through M-5. Installation and construction of the well(s) is described in Attachment L.

M.2 PROPOSED CEMENT DESIGN

The cement design for the casing strings is shown in Table M-1. The cement has been recommended by Franklin Well Service and modified by WSP. Cement volumes will be based on a minimum of 120% of the open-hole/casing annular volume as determined by a four-arm caliper measurement of the open hole.

M.3 PROPOSED TUBULAR AND PACKER SPECIFICATIONS

The specifications for the casing, tubing and packer are included in Table M-2. The intermediate (long string) casing has been designed for a setting depth of 3,490 feet bgs.

M.4 WELLHEAD CONSTRUCTION DETAILS

The proposed well head is shown on Figure M-6.

M.5 LOCATION OF SAMPLE TAP AND FEMALE COUPLING FOR INDEPENDENT DETERMINATION OF ANNULUS PRESSURE

A needle valve, with a ½-inch female connection, will be installed on the tubing head outlet between the injection tubing and the casing annulus for an independent pressure gauge. An independent ½-inch tap will be provided on the flowline inlet to the well for independent measurement of injection pressure (Figure K-3).

List of Tables for Attachment M

List of Figures for Attachment M

TABLE M-1

SPECIFICATIONS FOR CEMENT FOR ALL CASING STRINGS
BUCKEYE TERMINAL, LLC
WOODHAVEN TERMINAL
WAYNE COUNTY, MICHIGAN

Interval	Casing Size (inch)	Hole Size (inch)	Interval (feet below ground surface)	Ideal Cement Volume x 1.2 (ft^3)	Cement Type From Haliburton Recommendation Volume to be based on 120% of caliper
Conductor	20	N/A	50	Driven	
Protection	13 3/8	17 1/2	0-470	459 cu. ft.	**Surface Casing (production)** 10 / 8 Franklin Salt System 225 sacks Class "A," + 10% (BWOC) Cal - Seal (GYPSUM) + 8% (BWOW) salt ~~+ .6% fluid loss~~ + 5# Kol Seal (LCM) + 1/8# Poly-Flake (LCM) yield 1.7 cf/sk density 14.2 PPG water 8.0 gal/sk
Intermediate 1 (Long String)	9 5/8 (40 PPF)	12 1/4	0-1310	513 cu. Ft.	**Intermediate (long string)** 150 BBL Mud Flush **Lead** 10 / 8 Franklin Salt System 185 sacks Class "A," + 10% (BWOC) Cal-Seal (GYPSUM) + 18% (BWOW) salt + .6% fluid loss + .2% retarder + 5# Kol Seal (LCM) + 1/8# Poly-Flake (LCM) yield 1.75 cf/sk density 14.4 ppg water 7.9 gal/sk **Tail** 10 / 8 Franklin Salt System 112 sacks Class "A," + 10% (BWOC) Cal-Seal (GYPSUM) + 8% (BWOW) salt + 6% fluid loss + 5# Kol-Seal (LCM) + 1/8# Poly Flake (LCM) yield 1.7 cf/sk density 14.3 ppg water 8.0 gal/sk
Intermediate 2 (Production String)	5 1/2	8 3/4	0-3490	1083 cu. Ft.	**Intermediate (production string)** 245 BBL Mud Flush **Lead** 10 / 8 Franklin 391 sacks Class "A" cement + additives TBD yield 1.75 cf/sk ~~density 14.5~~ ppg water 7.9 gal/sk **Tail** 10 / 8 Franklin 236 sacks Class "A" cement + additives TBD yield 1.7 cf/sk density 16 ppg water 8.0 gal/sk

NOTES:

BWOC - Amount in percent of material added to cement.

BWOW - Amount in percent of a material added to a cement slurry based on the weight of water.

cf/sk - cubic foot per sack

LCM - Solid material intentionally introduced into a mud system to reduce and eventually prevent the flow of drilling fluid into a weak, fractured or vugular formation.

gal/sk - gallons per sack

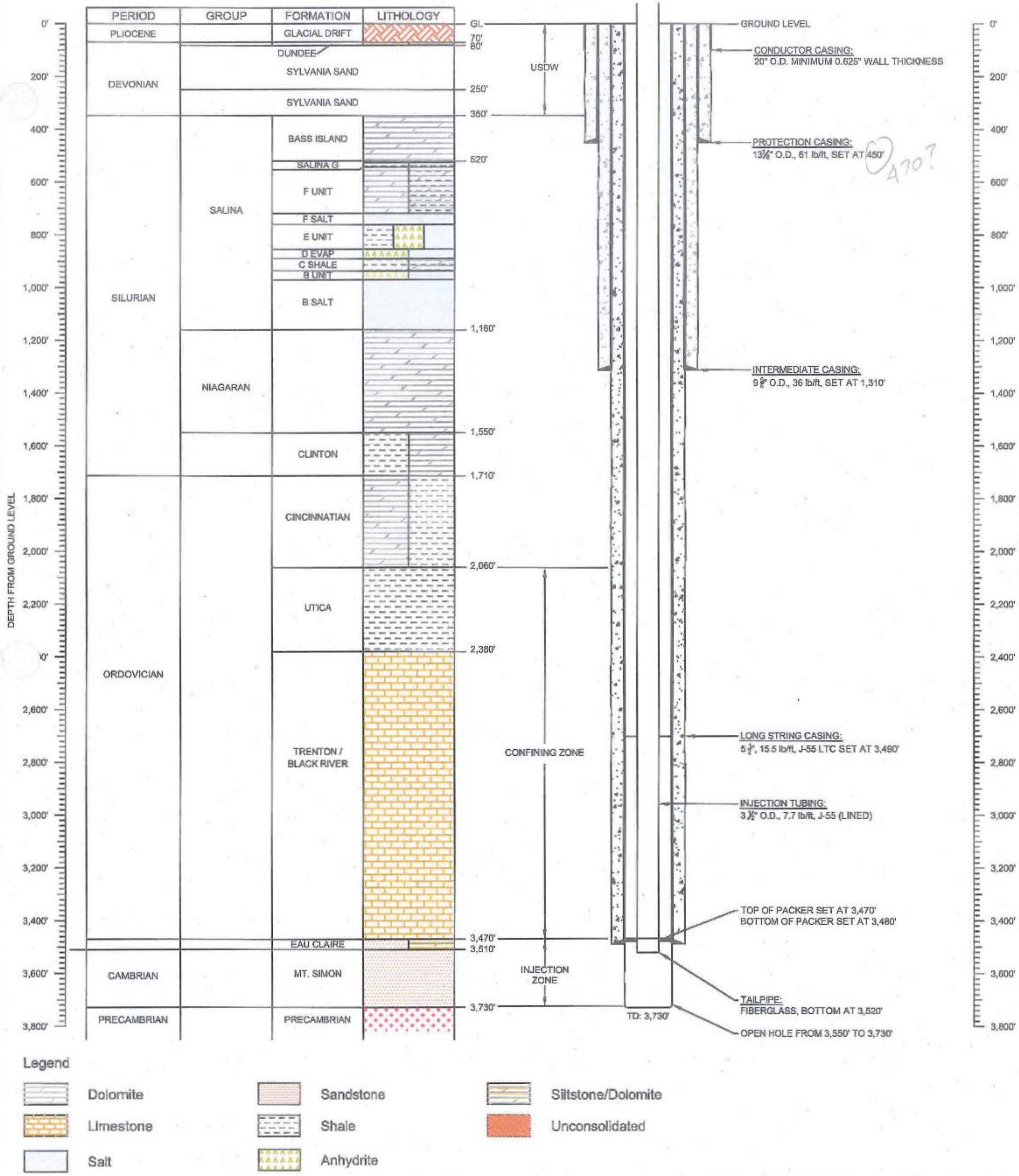
PPF - pounds per foot

ppg - pounds per gallon

TABLE M-2
Specifications for Casing, Tubing and Packer

Ref	Section	Outside Diameter (in)	Setting Depth (feet BGL)	Material	Collapse Resistance (psi)	Internal Yield (psi)	Tensile Strength (psi)	Maximum External Press (psi)	Maximum Internal Press (psi)	Maximum Tensile Load (lbs)	Safety Factor Collapse	Safety Factor Burst	Safety Factor Tension
	Conductor	20	50	133 ppf; 0.625" wall, N-80, STC or Welded	1600	4450	1,707,000	NA	NA				
1	Protection	13.375	470	61 ppf; J-55; STC	1,540	3,090	595,000	152	1,000	28,670	10.2	3.09	20.8
2	Intermediate	9.625	1310	36 ppf; J-55 (or K-55); STC	2,570	3,950	394,000	422	1,500	47,160	6.1	2.63	8.4
2	Long String	5.5	3490	15.5 ppf; J-55; LTC	4,040	4,810	202,000	1125	1,500	54,095	3.6	3.21	3.7
3	Injection Tubing	3.5	3,470	7.7 ppf; J-55; LTC	5,970	5,940	89,840	1861	5,000	26,719	3.2	1.19	3.4
	Injection Packer	5.5	3,470	Compression set retrievable double grip carbon steel									

1. Maximum external pressure after cementing 14.2 ppg cement with fresh water inside. Assumed gradient equal to 8.0 ppg. Maximum internal pressure during pressure test at 1000 psi.
2. Maximum external pressure after cementing 14.2 ppg cement with fresh water inside. Assumed gradient equal to 8.0 ppg. Maximum internal pressure during pressure test at 1500 psi.
3. Maximum external pressure during APT with 10.0 ppg brine and 1500 psi test pressure. Maximum internal pressure during stimulation set at 5000 psi.



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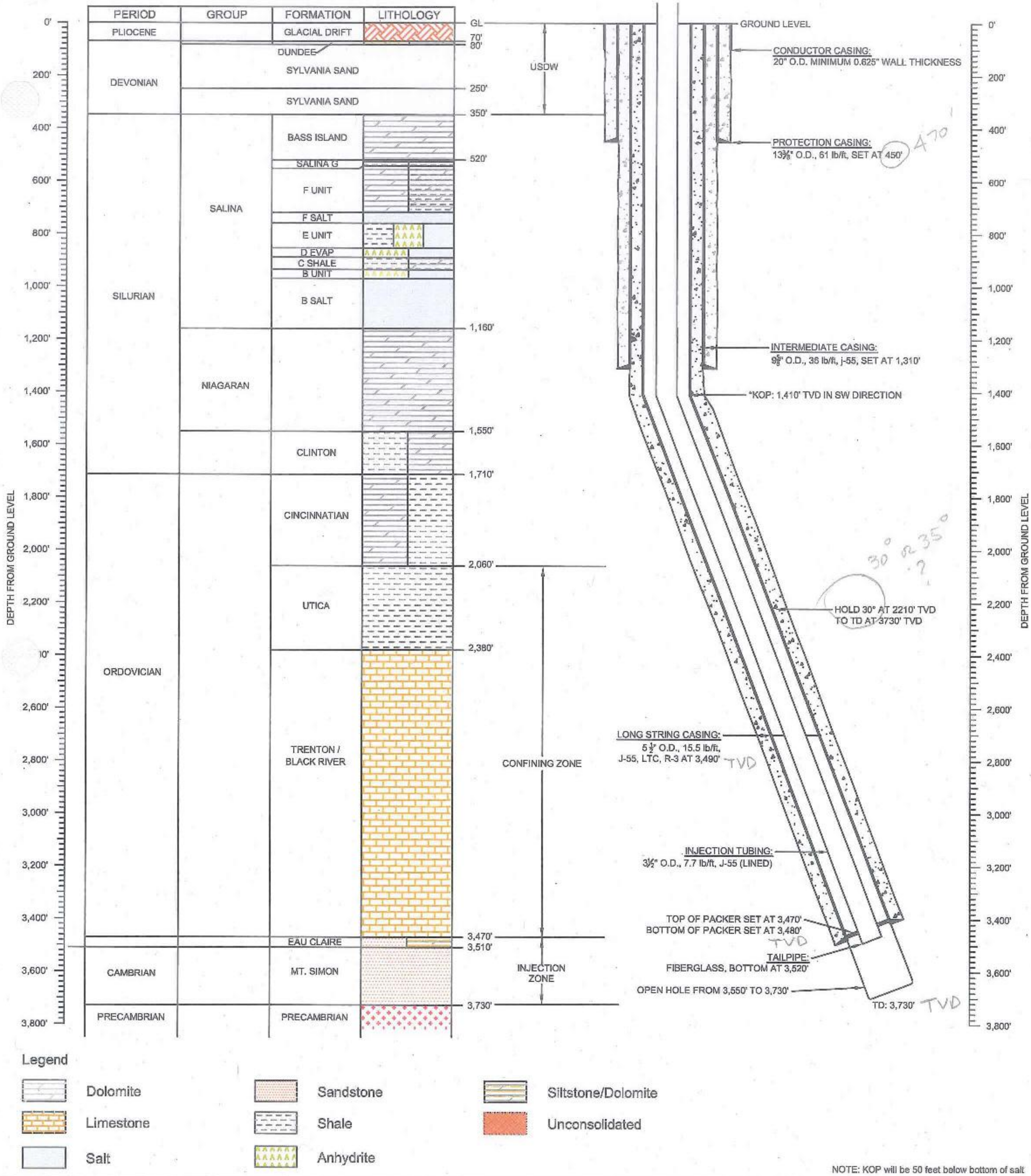
WAYNE COUNTY, MICHIGAN

PROPOSED BDW-1 WELL CONSTRUCTION AND STRATIGRAPHY

Job No. 192065A–Rev–2

Design: WDD	Drawn: WDD	Checked: GM	Date: 08/21/17	Scale: NTS	Figure No. M–1



NOTE: KOP will be 50 feet below bottom of salt

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PROPOSED BDW-2 WELL CONSTRUCTION AND STRATIGRAPHY

Job No. 192065A–Rev–2

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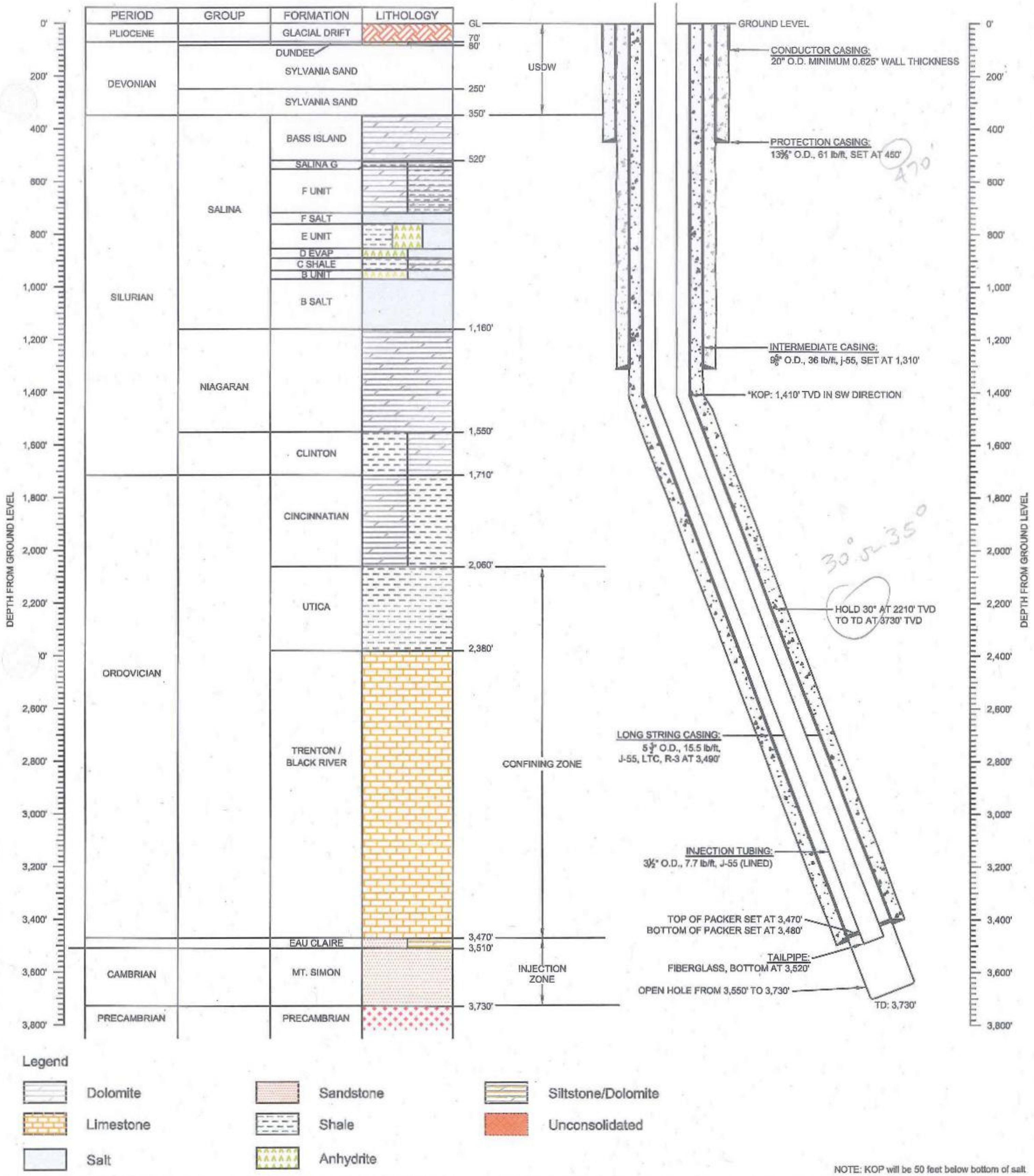

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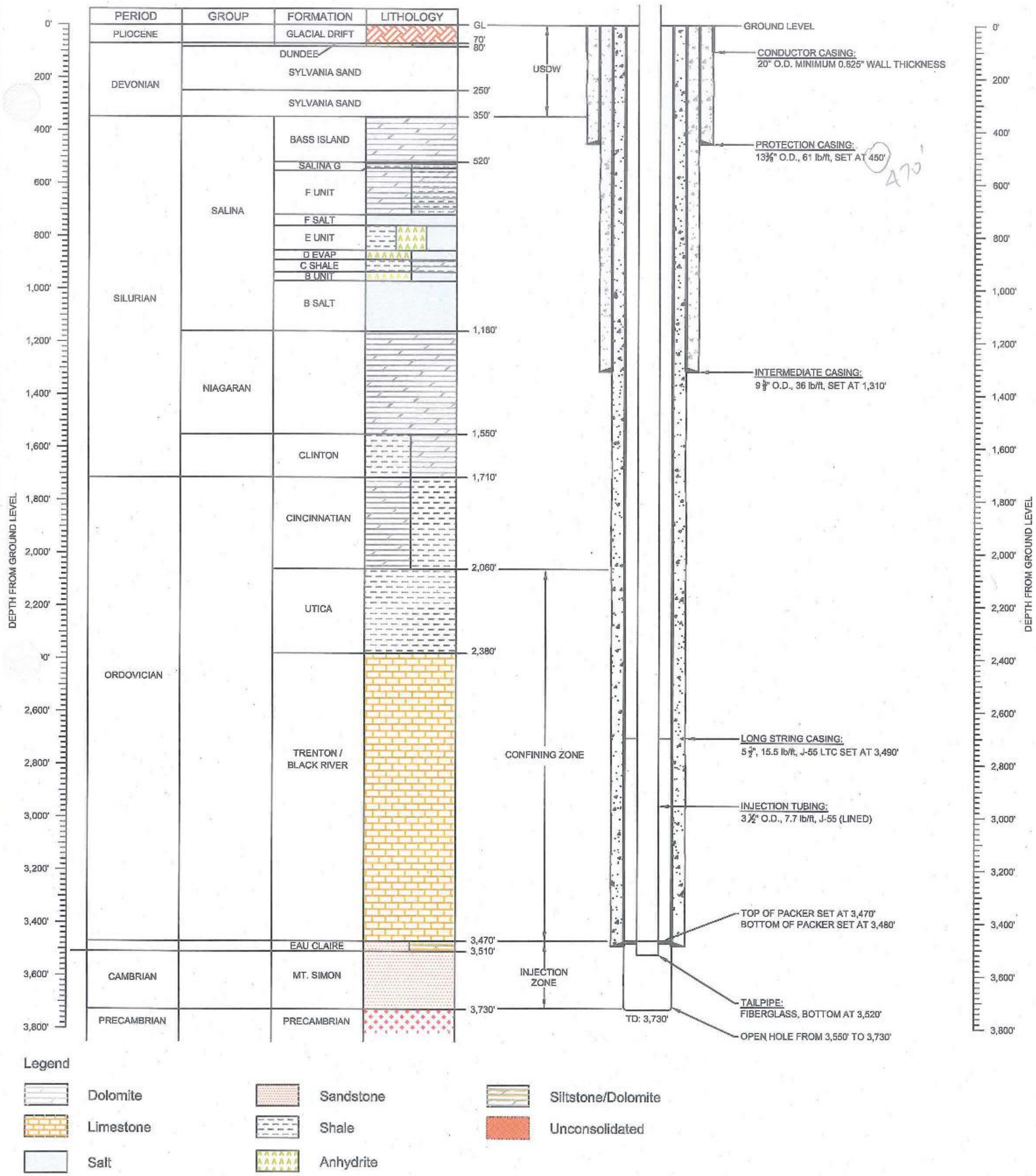
PROPOSED BDW-3 WELL CONSTRUCTION AND STRATIGRAPHY

Job No. 192065A–Rev–2

Design: WDD	Drawn: WDD	Checked: GM	Date: 08/21/17	Scale: NTS	Figure No. M–3



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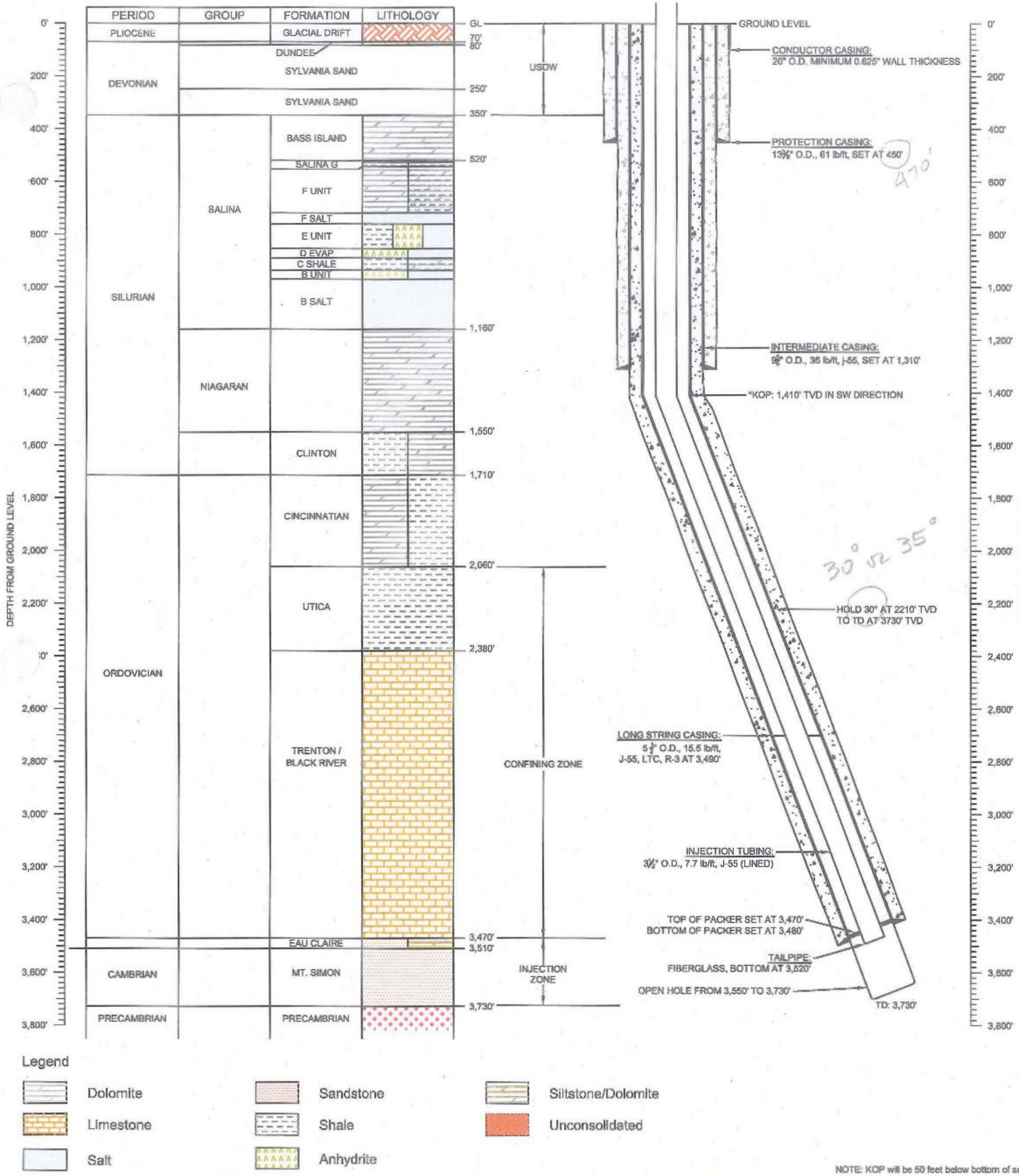
PROPOSED BDW-4 WELL CONSTRUCTION AND STRATIGRAPHY

Job No. 192065A–Rev–2

Design: WDD	Drawn: WDD	Checked: GM	Date: 08/21/17	Scale: NTS	Figure No. M–4



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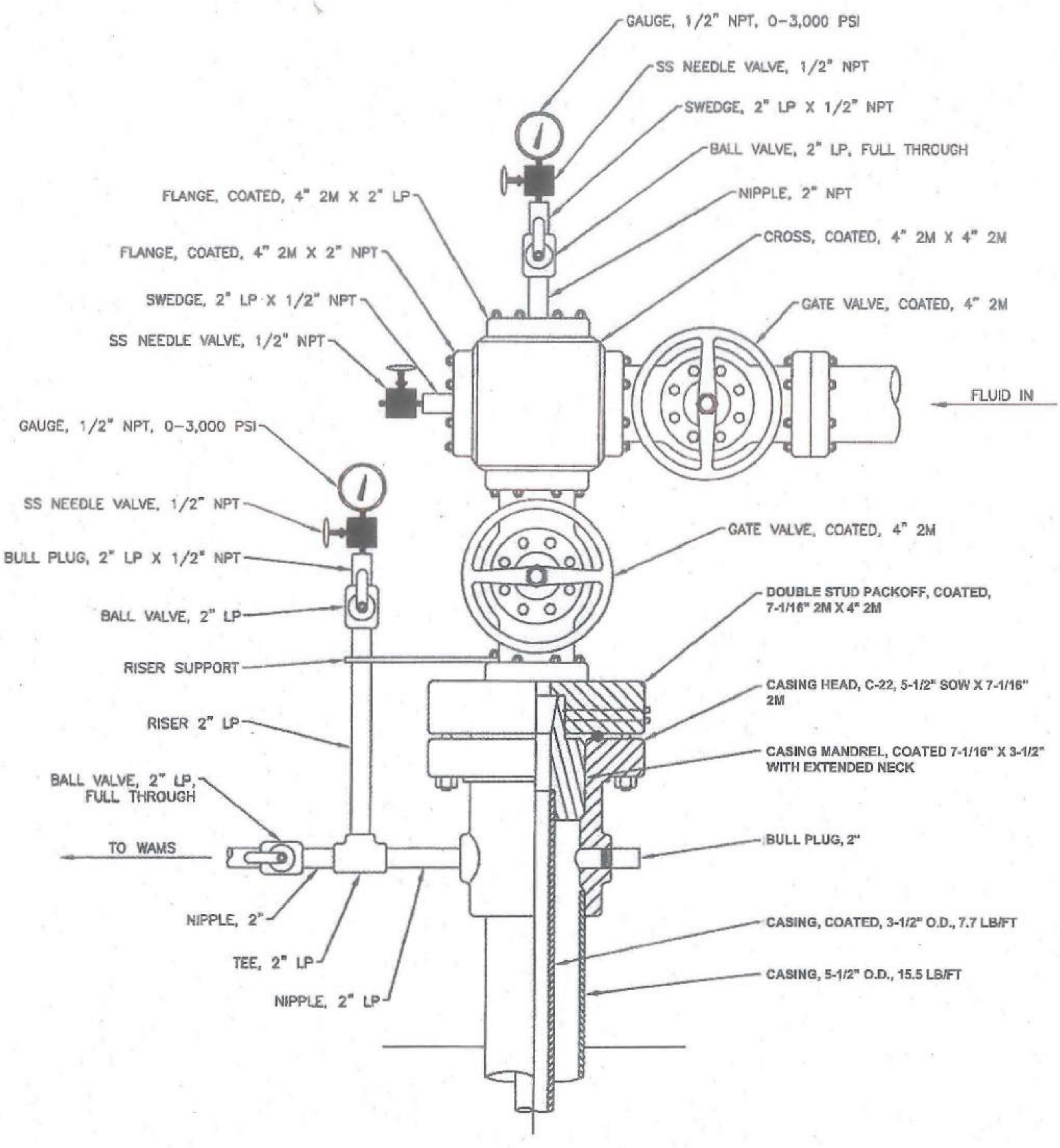
PROPOSED BDW-5 WELL CONSTRUCTION AND STRATIGRAPHY					Job No. 192065A–Rev–2
Design: WDD	Drawn: WDD	Checked: GM	Date: 08/21/17	Scale: NTS	Figure No. M–5



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PROPOSED WELLHEAD SCHEMATIC

Job No. 192065A–Rev–2

Design: CRB	Drawn: WDD	Checked: GM	Date: 08/21/17	Scale: NTS	Figure No. M–6

O. PLANS FOR WELL FAILURES

The purpose of the Class I injection wells is to supply a means to dispose of brine water generated from the solution mining of caverns developed in the Salina B Formation.

In the event a failure occurs to any one of the injection wells, the well will be shut-in immediately and injectate shifted to other wells to prevent migration of fluids into any USDW. See Attachment P, Well Monitoring Program, for description of method used to monitor for well failure. If it is determined that the well has lost mechanical integrity, the necessary measures will be taken to assess the cause(s) of lost mechanical integrity, and a work plan for restoring mechanical integrity will be developed and submitted to the EPA Region 5, for approval. Once regulatory approval has been obtained, the work plan will be implemented to restore mechanical integrity to the well. When mechanical integrity of the well can be demonstrated to EPA Region 5, regulatory approval to restore operation will be obtained prior to resuming injection. A final report documenting the well work performed and mechanical tests run will be prepared and submitted to EPA Region 5.

P. MONITORING PROGRAM

P.1 WASTE ANALYSIS PLAN

The proposed Waste Analysis Plan is included as Appendix D.

P.2 MONITORING AND RECORDING SYSTEM FOR INJECTION PRESSURE, RATE, VOLUME, AND ANNULUS PRESSURE

146.23(a)(6)

The injection wells will be operated on-site. The operating system will be designed to control the well from a dedicated computer terminal with a continuous monitoring and recording system for injection pressure, rate, volume, and annulus pressure. The system will have the capability to interface and deliver selected data to the station archive. The system will have the capability of long term storage of process data by being archived within the plant control system electronically. The recording system will be physically located on site.

The pressure transducer for the injection pressure will be located near the wellhead. In the event the injection pressure is outside the desired pressure bounds, the computer will automatically interface with the facility control system and send an alarm to the terminal notifying the operator.

The monitoring and recording system for the injection rate will use an inline flow meter that will be located between the injection pumps and the wellhead. Associated with the flow meter will be a volume totalizer that will keep track of the total gallons of fluid injected. In the event the injection operation is outside the desired rate bounds, the computer will automatically interface with the facility control system and send an alarm to the terminal notifying the operator.

The pressure transducer for the annulus pressure will be located near the wellhead. In the event the annulus pressure is outside the desired pressure bounds, the computer will automatically interface with the facility control system and send an alarm to the terminal notifying the operator. WHERE IS THAT LOCATED? SEE SEC. K.2

The injectate specific gravity will be measured at the sampling location with a salinometer or similarly accurate instrument. Measurements will be conducted daily during the cavern solution mining process as the specific gravity. The specific gravity will range from the minimum to maximum requested specific gravity during cavern development. During cavern hydrocarbon storage, injection will become intermittent and the injectate specific gravity will remain saturated or near saturated (approximately specific gravity of 1.20). Therefore, following completion of cavern solution mining, the specific gravity will be measured at the well location weekly.

P.3 SIGHT GLASS LEVEL MONITORING AND RECORDING

The top 10 feet of the well annulus will be filled with a fluid capable of resisting freezing. The seal pot system will also be filled with this same fluid to prevent freezing problems near the surface. Nitrogen will be used to pressurize the seal pot. Two pressure transducers, one at the top of the seal pot and one at the bottom of the seal pot, will be used to determine the height of the liquid in the sight glass.

The annulus pressure will be maintained 100 psi above (differential) the injection pressure. A nitrogen pressure regulator will be used to regulate the annulus pressure.

P.4 GROUNDWATER MONITORING PLAN AND QUALITY ASSURANCE PROJECT PLAN

Due to the nonhazardous nature of the injectate, neither a groundwater monitoring plan nor a Quality Assurance Project Plan will be required.

Q. PLUGGING AND ABANDONMENT PLAN

A completed EPA Plugging and Abandonment Plan (EPA Form 7540-14), including a detailed estimate of plugging and abandonment costs, has been included as Appendix E. This cost estimate may be used for each of the wells due to the expected similarity of design and construction. The form was completed by WSP, an independent firm.

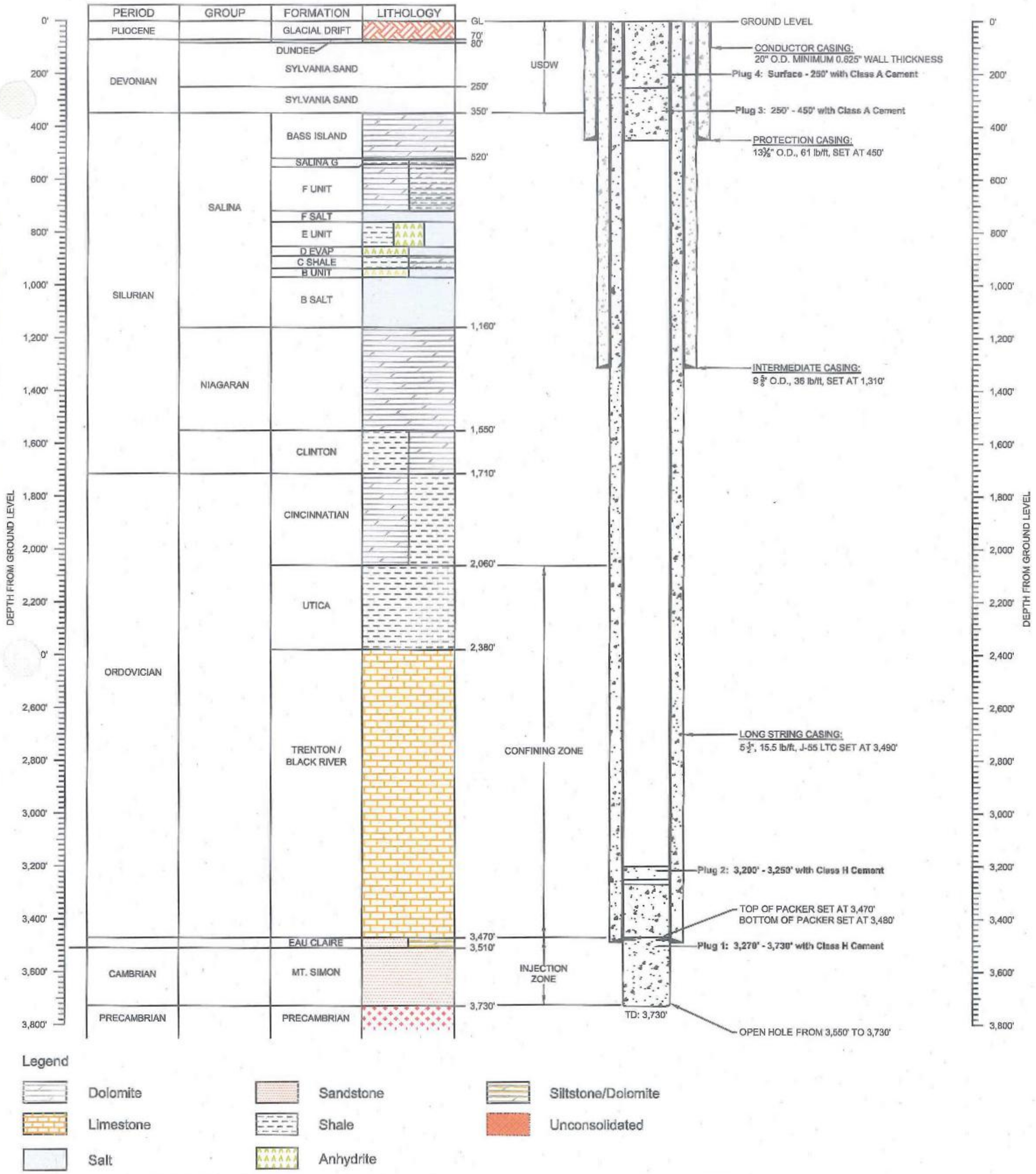
The following general closure procedure will be used to permanently plug and abandon the injection wells:

1. Prepare well and location for plugging. Remove surface facilities, well annulus maintenance system and injection piping.
2. Move in and rig up workover rig and associated equipment.
3. Remove wellhead assembly and install blowout preventer (BOP). $1.18\ ft^3/sx$
4. Release injection packer. Pull and lay down the injection packer and injection tubing.
5. Go in the hole open end with workstring to total depth and set balanced Class "H" cement plug (15.6 pounds per gallon [ppg] slurry weight) across open hole section and 200 feet into protection casing. Pull up several stands and reverse out. Wait for cement to cure.
6. Tag top of cement and displace wellbore with appropriate weight mud (as determined from injection zone pressure) by circulating until equilibrium is achieved. Run bridge plug and set +/- 20 feet above the top of cement. Pressure test plug to 500 psig.
7. Mix and set 50 feet of Class "H"cement (15.6 ppg) on top of bridge plug. Wait for cement to cure.
8. Tag top of cement plug. Pressure test plug to 500 psi for 30 minutes.
9. Set a 200 foot balanced Class "A" cement plug (15.6 ppg) 100 feet above and below the base of the USDW. Wait for cement to cure. $1.18\ ft^3/sx$
10. Tag top of cement plug and pressure test to 500 psi for 30 minutes.
11. Set cement plug from +/- 250 feet to the surface and top out annular area around protection and surface casing and conductor if necessary.
12. Nipple down the blowout preventer and cut off all casing 3 feet bgs. Weld a 1/2-inch steel plate over the casings and inscribe with appropriate identifying information.
13. Rig down and move out workover rig and associated equipment.
14. Clean and level location to grade.

Figures Q-1 and Q-2 illustrate the proposed plugging and abandonment for both the vertical and directional wells.

Since the proposed wells will be nonhazardous, no closure or post-closure care plans are required.

List of Figures for Attachment Q



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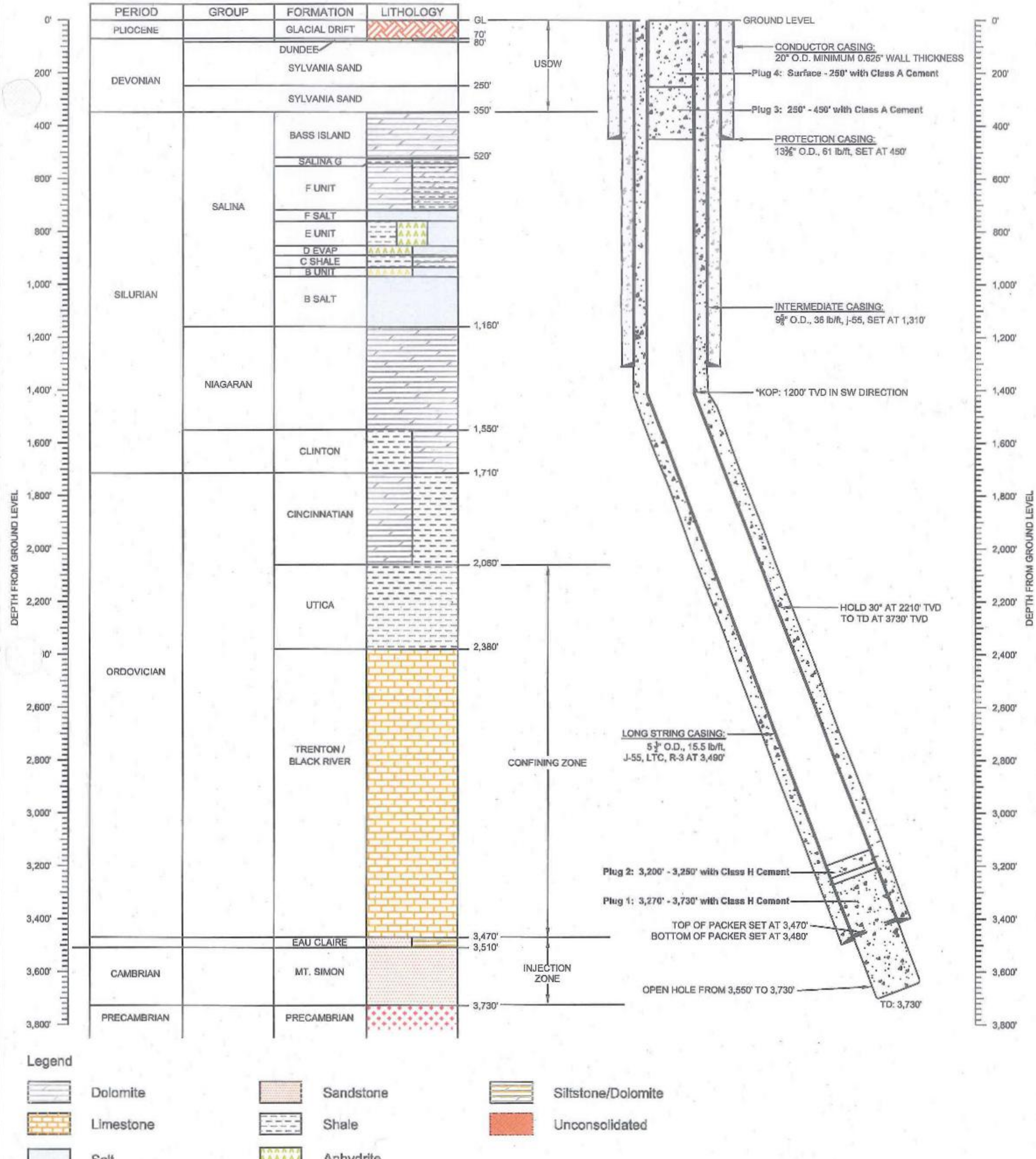
PROPOSED VERTICAL PLUGGING & ABANDONMENT SCHEMATIC

Job No. 192065A–Rev–2

Design: WDD	Drawn: WDD	Checked: GM	Date: 08/21/17	Scale: NTS	Figure No. Q–1



NOTE: KOP will be 50 feet below bottom of salt

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PROPOSED DIRECTIONAL PLUGGING & ABANDONMENT SCHEMATIC					Job No. 192065A–Rev–2
Design: WDD	Drawn: WDD	Checked: GM	Date: 08/21/17	Scale: NTS	Figure No. Q–2

R. NECESSARY RESOURCES

See attached documentation.